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Restructuring and Electricity Prices in Washington:
A review of the significance of the EIA Study, *Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities*,
and comments on preserving the benefits of low-cost power in an increasingly competitive environment.

Mr. Chairman, members of the committee, thank you for the opportunity to testify today. This hearing represents a timely inquiry into a crucial question: "How will restructuring of the electric power industry affect our current low prices?" This is a particularly appropriate venue for such an inquiry. Ultimately, the answer to the question will be determined by the extent to which state and federal policy-makers shape competitive markets in a way that affirms the uniquely valuable features of our existing regional power system.

INTRODUCTION AND SUMMARY OF CONCLUSIONS

The Energy Information Administration report, *Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities*, has generated a great deal of controversy since its release in August of this year. The report concludes that the average price of power for consumers in the Northwest could rise significantly if retail access leads to marginal cost pricing of electricity. These results should be viewed with a great deal of caution, for two primary reasons:

First, the EIA study usefully highlights the essential challenge of restructuring for the Northwest: how to preserve our low-cost power in a competitive environment where the value of that power becomes more widely apparent. It does not, however, indicate the best way to respond to that challenge.

Most importantly, the study does not suggest that deferring state action to restructure our retail electricity markets is the most appropriate strategy for preserving low-cost power. Restructuring the retail market in Washington (particularly along the lines of the "portfolio" model currently under discussion) is not an automatic step in the direction of EIA's verdict on Northwest electricity prices. On the contrary, depending on how it is structured, it may well be an important step away from that verdict. In its analysis, EIA assumes that Washington no longer enjoys the historical and legal rights to the benefits of the region's low cost public resources, and that the value of those resources is redistributed throughout the western market. That result is a real danger, but it is by no means the inevitable result of market forces. The key question for Washington policy-makers is how to avoid such a result. The EIA study offers little guidance on that question.

Second, the EIA study relies on a number of assumptions and modeling techniques that, taken together, may not produce a realistic picture of a deregulated Northwest electricity market. EIA's treatment of the Northwest natural gas market and electricity exchanges with Canada, in particular, may result in an overstatement of Northwest electricity prices under competition. On the other hand, EIA does not account for a variety of long-term pressures on gas prices, including regulation of carbon dioxide emissions to mitigate global climate change that may push electricity prices up in the future.

However, even under a wide range of assumptions about how markets will evolve, the most important implication of the EIA study holds true: the region's existing electric power resources are likely to yield substantial net benefits in the coming decades. EIA implies that those benefits would be worth about $3 billion per year. Their true value may well be different, but it is almost certainly greater than zero. And as the EIA study also implies, with the growth of an increasingly competitive power market throughout the western U.S., pressure to redistribute that value to consumers in other states is mounting.

The challenge for Northwest policy-makers, then, is to retain the benefits of our existing electric power resources for present and future citizens in an increasingly competitive environment. While decisions regarding the disposition of the bulk of these benefits may ultimately rest with Congress, state decisions regarding the nature of the retail market may have an important influence on our prospects for retaining the value of these resources. In particular, state decisions may affect the likelihood of a successful effort to embrace the long-term costs and benefits of the federal hydropower system on the Columbia and Snake Rivers through the "subscription" process. State restructuring efforts that recognize and protect the uniquely valuable characteristics of our system may also reduce the likelihood of being pre-empted by federal legislation that would be less favorable to Northwest interests.

1. **THE EIA STUDY ASSUMES AWAY MANY OF THE CONDITIONS THAT MAKE WASHINGTON'S ELECTRIC POWER SYSTEM UNIQUELY VALUABLE. THE CHALLENGE IS TO DEVISE A STRATEGY THAT ADAPTS TO CHANGES IN THE MARKET WHILE PRESERVING THOSE ESSENTIAL CONDITIONS**.

The EIA study graphically affirms what we already know to be true: we in the Northwest enjoy the nation's cheapest electrical power. Another way of expressing this conclusion is to say that, in a relatively unrestrained market environment, our power would probably be worth more than we pay for it. The EIA study also shows how, under some circumstances, economic forces and the advent of competition could redistribute that surplus value outside the region. In this sense, the study is a useful reminder to Northwest policy-makers: Economic and political pressures to redistribute the value of our existing electric power resources appear to be growing. The recent study by the Congressional Budget Office which concludes that selling BPA could yield substantial benefits to taxpayers is another indication of the same pressures.

If we take EIA's conclusions at face value, the market value of our current electric power resources exceeds our power bill by roughly $3 billion each year. There many reasons why we may choose not to take EIA's conclusions at face value. In particular, several of EIA's key assumptions about gas prices and power exchanges with Canada are subject to debate. However, the most salient conclusion to be drawn from EIA's report holds true over a very wide range of alternative assumptions: *Even if gas prices are significantly lower than EIA projects, the marginal cost of power in foreseeable future markets is very unlikely to be less than the average cost of our existing resource mix*.

The EIA study is primarily a description of how *economic theory* predicts that the value of our system will be redistributed under a particular set of assumptions about nationwide retail access and marginal cost pricing. Actual restructuring initiatives will almost certainly create different market conditions than those assumed by economic theory. Indeed, to the extent that EIA's depiction of how economic theory would work is accurate, Northwest policy-makers may well want to create conditions that depart from economic theory.

Price regulation is one way in which our present system departs from a pure market model. But perhaps an even more important difference between our present system and the market model that EIA constructs is the extent to which our current electric power sources are under public ownership and are subject to public and regional preference. EIA's analysis assumes that under nationwide retail access, these conditions would not exist. Yet these are arguably the very conditions that make our power so affordable. Economic theory will not dictate whether these conditions persist. Policy-makers at the federal, regional, and state levels will.

Publicly-Owned Generating Resources

In calculating market-clearing prices for the region, EIA does not distinguish between publicly- and privately-owned generating resources. The treatment of publicly-owned generation under retail access is a huge question mark, however. Will the output of the Federal Columbia River Power System continue to be sold at cost, or will it go to market as assumed by EIA? Will Washington public utilities that qualify for "preference" power from Bonneville be able to resell that power at market prices? Will public utilities be able to sell their own generation outside their jurisdictional boundaries without jeopardizing their tax-exempt status? Will public hydroelectric facilities remain public after increasingly competitive relicensing proceedings? If public power is sold at market prices, to whom will flow the stranded costs or positive net value associated with the difference between cost and market?

The question of what happens to publicly-owned generation under retail access is of enormous importance to Washington, as the following table indicates. Nearly 90% of the electricity generated in Washington is produced at publicly-owned facilities. The federal hydro system accounts for 45% of Washington generation, but an equally large share is attributed to non-federal entities such as the Washington Public Power Supply System, municipal utilities such as such as Tacoma and Seattle, and public utility districts such as Grant, Chelan and Douglas counties. Only 12% of electricity generated in Washington in 1995 came from investor owned utilities.

A more accurate gauge of the prominence of public power may be the percentage of Washington loads served by publicly-owned generation. The interstate nature of electricity flows makes this somewhat more difficult to estimate. Counting out-of-state purchases from private facilities to serve Washington loads, the portion of our power that comes from public sources is closer to two-thirds. The point remains, however, that the generation mix that most directly affects our prices is heavily dominated by public resources.

Electric Power Generation and Retail Sales in Washington, 1995

	Generation		Retail Sales	
Owner	GWh	% of State Total	GWh	% of State Total
Investor-Owned Utilities	11,517	12%	27,712	31%
WPPSS	6,942	7%	-	-
Cooperatives	-	-	2,784	3%
Municipal Utilities	10,339	11%	16,420	19%
Public Utility Districts	23,585	25%	25,856	29%
Federal Hydro System	43,284	45%	15,581	18%
Total	*95,667*	*100%*	*88,353*	*100%*

Sources: Form EIA-759, *Monthly Power Plant Report*; EIA, *Electric Sales and Revenue 1995*, Table 17.

The predominance of publicly-owned generation is one of the major differences between the electricity system in the Northwest and elsewhere in the country, and one of the reasons EIA's study is inadequate for modeling the Northwest system. EIA's model treats publicly-owned generating resources the same way it does private generation: all generation is deployed at market prices, and any difference between the market and cost is absorbed by shareholders and labeled "net stranded costs". Net stranded costs are positive when market prices for electricity are lower than average system costs and negative when market prices are higher. Because our prices are generally low now, many Northwest utilities may have negative stranded costs. Competition may therefore bring income from electricity sales beyond what public utilities with low-cost resources would have accrued under today's system of regulated prices.

EIA assumes this increased income accrues to utility shareholders. However, public utilities do not have shareholders. Since their consumers own them, they may choose to continue to sell power at cost even when it can command a higher price in a competitive market. If they do sell power at market, any net value they receive would presumably go back to the community in which they are located. There may, however, be limits on public utilities' ability to sell at market, particularly outside their service territories, due to concerns about private use of tax-exempt financing, anti-trust violations, and resale of preference power.

(It is worth noting that EIA's assumption that all differences between market and cost flow to shareholders may not be a realistic one *even for investor-owned utilities.* All states that have passed restructuring legislation have made some provision for recovery of "stranded costs" - the above-market costs that were incurred under a monopoly system that cannot be recovered in a competitive system. Investor-owned utilities have successfully argued that they incurred many of these costs under explicit authorization from the state pursuant to a regulatory obligation to serve, and should therefore be entitled to recover them during the transition to competition. Regulators and policy-makers in low cost states may well use the same logic that justifies stranded cost recovery to confer some of the benefits of below-market resources on the customers who paid for those resources in their regulated rates prior to competition.)

The Federal Columbia River Power System (FCRPS)

Perhaps the single biggest factor in determining how Washington consumers fare under retail access is the disposition of the benefits of the Federal Columbia River Power System. This system was built at taxpayer expense and is paid for over time through electric power rates. The system's "firm" output is made available on a priority basis to public agencies (PUDs, municipals, and co-ops, for example) and residential and small farm customers of investor-owned utilities. Regional users of the system, including Direct Service Industries, enjoy statutory preference over out-of-region users.

This preferential access to the benefits of the FCRPS has been an enormous source of benefit to the region for the past half-century. The magnitude of those benefits in the future is uncertain, but likely to be large. After many decades without competition in which BPA (the marketer of the FCRPS' output) was by far the cheapest wholesale power provider, market prices actually dipped below BPA's in 1995. BPA's prices have risen significantly only once its history, a roughly 500% increase from 1979 to 1983 to cover the costs of the WPPSS nuclear program. Since then, its prices have declined in real terms. So the recent convergence of BPA prices with market prices was not the result of rising costs at BPA. Rather, it resulted from two primary factors: 1) Wholesale deregulation has temporarily glutted western power markets with surplus power that had been held in reserve prior to deregulation; and 2) Low gas prices. Market prices may well rise when the surplus is exhausted, but will still be substantially lower than they were in the past due to dramatic improvements in the combustion turbine technology that burns gas to produce electricity. Advances in fuel cell and micro-turbine technologies may also offer low-cost alternatives in the future.

Forecasts of the future value of BPA resources depend very heavily on the market. Like all forecasts, they are speculative. However, there are many reasons to believe that over time, BPA is likely to be a low-cost provider. As surpluses erode in the western system, wholesale prices are likely to rise to reflect the capital costs associated with building new resources. These capital costs are likely to be higher than under a regulated system, because the owners of new resources will probably not have a regulatory assurance of cost recovery, as they have in the past. Higher capital costs may affect prices in two ways: by raising the total cost of a given resource, and by changing the mix of new generating resources toward those, like gas-fired combustion turbines, with relatively low capital costs and high operating costs. To the extent that these new resources are fossil-fueled, they may also be subject to fuel price volatility and environmental regulation, perhaps including new regulations on carbon emissions to curb global climate disruption. In contrast, BPA's costs are relatively stable. The costs associated with salmon recovery and nuclear decommissioning are sources of uncertainty. However, the largest unproductive cost in the BPA system - WPPSS debt - will begin to tail off in fifteen years and be retired completely by 2018.

Nevertheless, in the short term, when BPA prices are slightly above market, there is a temptation on the part of wholesale purchasers and DSIs to switch to other sources of supply. If BPA is unable to recover its costs from Northwest customers in the short-term, it will be increasingly difficult to defend our preferential access to future benefits in Congress.

Recognizing this predicament, the Governors of Washington, Oregon, Idaho and Montana convened a *Comprehensive Review of the Regional Energy System* in 1996. The Review's Steering Committee concluded that the FCRPS is likely to be a significant continuing source of benefits in the future. (For scale: for every 1 cent per kWh by which BPA prices are lower than the market, the region reaps nearly $1 billion in benefits.) Accordingly, they recommended a subscription process through which utilities and DSIs in the region maintain preferential rights to the system's output to the extent that they commit to cover its costs. Ironically, the region's best (and perhaps last) opportunity to secure the benefits of the FCRPS for the future may be now, when BPA prices are slightly above market. When BPA is once again a significant producer of net benefits, it is less likely that Congress will miss the opportunity to redistribute those benefits to other parts of the country or taxpayers generally. The EIA study highlights this prospect in stark terms; EIA simply assumes away public and regional preference and distributes the benefits of the FCRPS in accordance with market theory.

So, while EIA's conclusions are not the inevitable consequences of electric industry restructuring, they do suggest some very real economic and political pressures that may be brought to bear on our historically low prices. The urgent question for Washington then becomes: How do we preserve the value of our low-cost resources for present and future generations of Washington consumers? In response to the EIA study, some have suggested that avoiding or deferring action to restructure the retail market in Washington is the appropriate strategy. However, state action that recognizes and affirms the unique features of our electric power system may be a more successful strategy.

2. EIA'S ASSUMPTIONS ABOUT NATURAL GAS MARKETS AND ELECTRICITY TRADE WITH CANADA MAY NOT ACCURATELY REFLECT ACTUAL NORTHWEST CONDITIONS. NEVERTHELESS, OUR EXISTING RESOURCES ARE VERY LIKELY TO REMAIN VALUABLE UNDER A WIDE RANGE OF FUTURE CONDITIONS.

For the Northwest region, EIA concludes that retail electricity prices will rise from approximately 4.5¢ per kilowatt-hour to around 6.2¢ in 1998. (Actual Washington prices averaged 4.2 cents per kWh in 1996, somewhat below the regional average.) EIA assumes that transmission and distribution costs account for 2.1 cents per kWh, so prices for electricity commodity would rise from 2.4 to 4.1 cents per kWh. There are two principal sources of this increase. First, existing plants throughout the West are dispatched, subject to interregional transmission constraints, in merit order to serve loads in all western states. This results in Northwest generators being dispatched to serve higher value loads in the Southwest. The second source is a "reliability price adjustment", representing an assumed value of unserved load of $3 per kilowatt-hour, which is invoked during hours when demand for electricity exceeds available supply. The reliability price adjustment raises prices above marginal operating costs during those hours, forcing demand to equal supply at all times and signaling the market to invest in new generating capacity. In the longer term, prices are capped at the cost of new capacity additions. A similar scheme is currently in place in the United Kingdom to encourage the construction of new capacity.

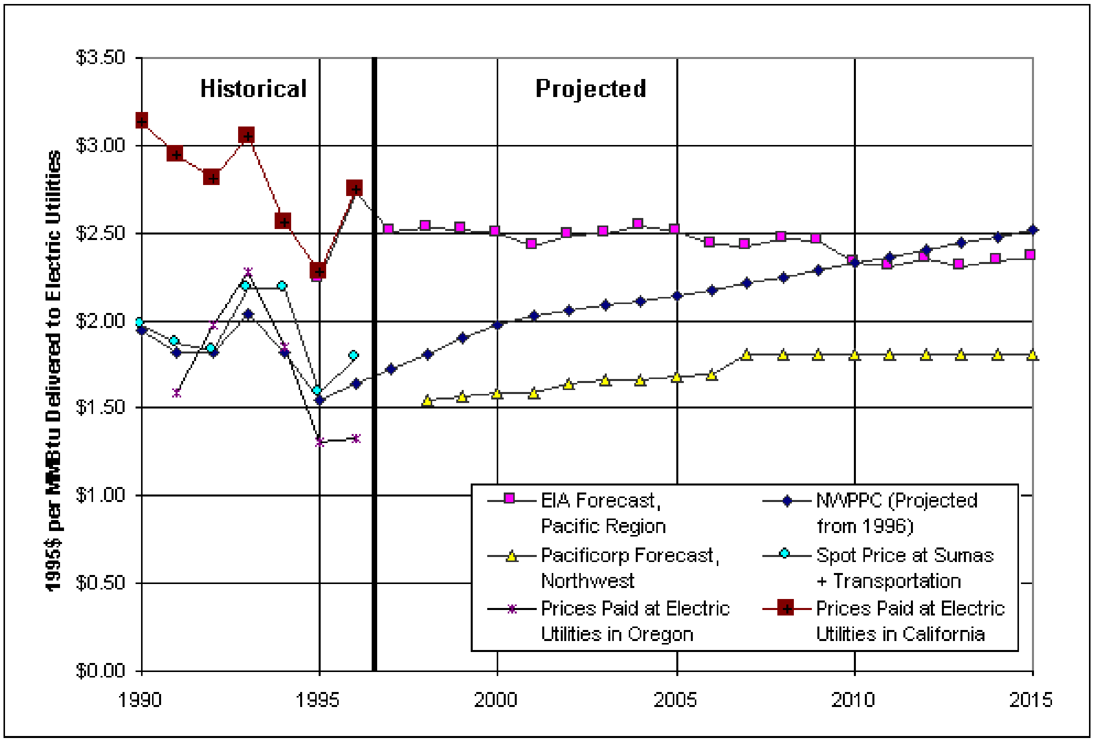
The following sections discuss two of the features of the EIA analysis that call into question its conclusions about power prices in the Northwest under nationwide retail access. It is not meant to offer a conclusive alternative to EIA's modeling effort, nor should it be construed as an independent forecast. Rather, it simply highlights some of the ways in which EIA's nationwide analysis departs from some of the conditions we observe in the Northwest. There are, of course, many other ways in which EIA's assumptions and modeling techniques are open to debate. The sections below on natural gas prices and trade with Canada are areas in which known or anticipated conditions in the Northwest are different from those assumed by EIA.

Natural gas prices

EIA's analysis assumes that prices in a competitive market will reflect marginal costs, and the marginal resource is almost always a gas-fired combustion turbine. EIA pegs the cost of new natural gas-fired generating capacity at roughly 4 cents per kWh. The Northwest Power Planning Council estimates the levelized cost of a new simple cycle combustion turbine to be 3.2¢ per kWh, and a combined cycle combustion turbine to be 2.6¢ per kWh.[1] Pacificorp's integrated resource plan expects that cogeneration will be available at a cost of 2.6¢ per kWh, and a combined cycle combustion turbine at 3.0¢ per kWh.[2]

The chart below shows that the primary reason for the disparity is the wide divergence in forecasts of natural gas prices. (Fuel accounts for the largest portion of the cost of a gas-fired combustion. Using assumptions from the Power Council's Draft Fourth Northwest Power Plan, and a fuel price of $1.80 per MMBtu, fuel accounts for 62% of the total life cycle cost of a combined cycle combustion turbine and 75% of the cost of a simple cycle combustion turbine.) Significantly, the divergence is at its widest during the historical period of 1995-1996. (Historical comparisons are difficult because the very small volume of natural gas currently used for electricity generation in the Northwest, and especially in Washington, raises questions about the applicability of historical price estimates to future electric generators.)

Natural Gas Price Comparisons



Sources: Energy Information Administration, *1997 Annual Energy Outlook*, Reference Case natural gas prices to electric generators, Pacific Region; Northwest Power Planning Council, *Draft 1996 Power Plan*, Medium Case; Pacificorp, *Draft Resource and Market Planning Program 5*, Table 4-15, October, 1997 (prices orginally stated in 1998 dollars, discounted by CTED to 1995 dollars assuming inflation of 3% per year); Energy Information Administration, *Natural Gas Annual.* Transportation costs on the Northwest Pipeline are 33.42 cents per MMBtu plus 1.9% for compressor fuel.

The most likely cause of the disparity between EIA and other estimates is EIA's geographical simplification of the national market for natural gas. In EIA's model, Oregon and Washington are placed together with California in the Pacific region. California consumes five times as much natural gas as Washington and Oregon combined, and gas prices in California have historically been ten to fifteen percent higher than in the Northwest.[3] Prices in EIA's Pacific region may therefore be dominated by events affecting California and the Southwest, and are more likely to reflect prices paid at electric generating plants in California than in the Northwest.

EIA's model also places Idaho, and the Pacific Gas Transmission (PGT) pipeline, in the Mountain region. The PGT pipeline transports gas from producing fields in Alberta to Washington, Oregon and California, and is the largest and often cheapest source of imports to West Coast markets. In EIA's model, the costs of Alberta gas are mixed with production and transportation costs of gas produced in the Southwest before a price for export to the Pacific region is calculated. The result is lower prices in the Mountain region and higher prices in the Pacific Northwest.

There is ample evidence to indicate that the Northwest has enjoyed an advantageous position in the nationwide natural gas market during the 1990s, a regional subtlety that is not captured in EIA's analysis. Spot prices at trading hubs in Washington and Idaho, for example, have been considerably lower than at other hubs in the west and in the nation during the past several years.

The degree to which this price advantage will persist is uncertain, however, and will depend largely on the extent of new pipeline construction.

Of course, forecasting the price of any commodity is a tricky business, and moving to an unregulated commodity price market would increase the region's exposure to volatility in natural gas prices. New pipeline projects currently in the planning stage would increase the ability of Canadian gas producers to move their product to higher value markets in the Midwest and Northeast. Strategies to reduce greenhouse gas concentrations and mitigate global climate change may well include efforts to internalize the cost of carbon dioxide emissions. This, in turn would increase the price of electricity from power plants fired by fossil fuels. And continued rapid increases in demand in West Coast markets could put pressure on existing production and transportation capacity, driving up costs. These vulnerabilities underscore one of the values of our existing (largely renewable) resource base and the importance of ensuring that restructuring efforts are designed to protect the value of those resources for Washington consumers.

Electricity Trade with Canada

Washington is interconnected with British Columbia by a transmission system with a transfer capability of 2300 MW. The United States has historically imported significant amounts of power from British Columbia. In the EIA model, the region is a net *exporter* of power in each year after 1997. The result is a reduction of 1200 aMW of electricity supply from Canada between 1995 and 1999. Because Canadian imports often consist of power generated by low-cost hydroelectric dams, they might provide a lower cost marginal resource than is currently considered in the EIA model.

Approximately half of the supply reduction is due to the fact that EIA treats power exported to Canada under the Columbia River Treaty (the Canadian entitlement) as if it were all consumed there. In fact, negotiations are currently underway in which the Canadians will likely specify a delivery point in the United States in order to facilitate the remarketing of that power to American customers. Relative to EIA's analysis, this would likely increase the number of hours when the marginal resource is low-cost hydro. In summary, a more realistic treatment of electricity trade with Canada in general, and the Canadian entitlement in particular, would probably yield lower estimates of market prices in the Northwest.

Notwithstanding flaws in the EIA analysis, our existing electric power resource base is likely to be less costly than marginal resources for the foreseeable future.

Legitimate critique of the EIA analysis should not distract us from the significance of its primary conclusions. Our existing electric resource base in Washington has an average cost very near 2 cents per kilowatt hour. Future trends in natural gas prices could bring the marginal cost of new gas-fired resources as low as 2 1/2 cents per kWh or as high as 4 cents, or perhaps more under an ambitious effort to stabilize greenhouse gas emissions. A more realistic treatment of power trades with Canada could decrease the marginal cost of power in the region relative to EIA estimates. But in almost no plausible scenario would the cost of our existing power sources exceed the marginal cost of supply in a fully competitive market for the foreseeable future.

This does not mean, however, that Washington should not undertake efforts to restructure its retail electricity market. As noted above, actual restructuring efforts would almost certainly depart significantly from the conditions assumed by EIA in its analysis. State restructuring designed to protect the unique features of our current electric power system may in fact help to forestall restructuring outcomes that are less favorable to Washington.

3. PRESERVING THE BENEFITS OF LOW-COST POWER IN WASHINGTON

If the EIA study draws attention to the enormous value in our system and the pressure to redistribute that value, it does little to inform our efforts to protect that value. Many of the decisions that will affect distribution of that value will not be made by the state Legislature. Congress, not the states, ultimately determines the disposition of the Federal Columbia River Power System. The effort to subscribe BPA power to regional customers is still in the formative stages, and the success of that effort may well determine the extent to which the system's benefits stay in the region. Washington is represented on a Transition Board that oversees implementation of the subscription process and the development of legislation regarding the BPA system. However, neither subscription nor of course Congress are under the direct control of state lawmakers.

Washington's other publicly-owned generating resources are at least in the first instance controlled by local boards that are not subject to state regulation (although public utilities are creatures of state law). In short, the substantial majority of the state's low-cost resources are not under the immediate, direct jurisdiction of the state.

However, state action with respect to the retail electricity market may have a number of important influences on the subscription process and on the likelihood that Congress will reallocate the benefits of the FCRPS. The following examples are not positions of CTED, but they do indicate the potential relationships between state actions and other decisions that will affect distribution of the benefits of our current system.

- The Comprehensive Review included a package of federal, regional, and state recommendations that was developed and agreed upon by a broad cross-section of interests. The consensus for federal legislative and/or administrative action to support subscription depends in part on state action with respect to the recommendations that fall in the state's jurisdiction. Our ability to retain the benefits of the regional system depends in part on regional consensus, which in turn depends on our ability to follow through - at least in broad terms - on the compromise positions reached by the Comprehensive Review.
- By clarifying the nature of the retail market in Washington, the state can reduce utilities' uncertainty regarding whom they will be serving in the future. This, in turn, reduces the uncertainty associated with subscribing to BPA. Restructuring proposals that retain some form of regulated service for "core" customers may provide another measure of certainty.
- By clarifying retail utilities' authority to recover from their retail customers the stranded costs that they may incur pursuant to their wholesale purchases from BPA, the state can make subscription less risky. Last year's Senate Bill 6006, for instance, included language favored by BPA customers that would have allowed them to recover stranded costs attributable to any contract with the Bonneville Power Administration. This would reduce uncertainty concerning how BPA's costs would be recovered in a restructured environment. Reducing that uncertainty is important for two reasons: 1) It helps BPA

customers calculate the risks and benefits of subscribing to BPA with greater precision, and 2) It indicates to the Administration and Congress that the State of Washington is making affirmative provisions to ensure that we continue to bear the costs of the regional system.

- State restructuring legislation can improve the prospects for subscription by firming up the in-region market for federal power. For instance, the state could clarify or enhance the ability of eligible customers to aggregate for priority access to federal resources. It could also require default suppliers or existing providers to offer customers federal power as one among a portfolio of options. Or it could link prices for regulated service to the price of power from the FCRPS.
- The state could provide some flexibility with respect to the requirements of restructuring legislation for full requirements customers of Bonneville.
- By adopting a restructuring model that fits Washington's unique characteristics and attempts to preserve the benefits of low-cost power in the state, the state could reduce the likelihood that federal restructuring legislation will impose a more generic model. This could also affect the prospects for legislation that redistributes the benefits of the FCRPS, since advocates of restructuring could use the state's inaction to justify efforts to make the benefits of the FCRPS more widely available to consumers throughout the west. (It is, of course, very difficult to predict the course of federal restructuring legislation; but it is possible to take state actions that reduce pressures for an unfavorable outcome at the federal level.)

This is by no means an exhaustive list of actions the state could take to protect the value of low-cost resources for Washington citizens in an increasingly competitive electricity market. As a general proposition, it seems likely that the more we can define the conditions for orderly competition in the Washington retail market, the more we can reduce the uncertainties that retail utilities presently face, particularly in their decisions regarding federal power purchases. Ultimately, our ability to make long-term commitments to federal resources is probably the single most important factor in determining whether we will retain the benefits of low-cost power in Washington.

CONCLUSION

The EIA report is more useful for the challenges it defines than for the outcomes it predicts. It underscores the enormous value in our existing system. It describes how existing economic and political pressures might redistribute that value. And hopefully, it sets in motion a focused discussion about what actions Washington can take to preserve the benefits of its low-cost power for Washington citizens.

Thank you again for the opportunity to testify.

NOTES

Note 1. Northwest Power Planning Council, *Draft Fourth Northwest Power Plan*, Appendix F, p. FNG 5, April, 1996.

Note 2. Pacificorp, *Resource and Market Planning Program*, Table 3-20, p. 85, November, 1995.

Note 3. Energy Information Administration, *Natural Gas Annual 1996*.